CALIFORNIA ENERGY COMMISSION

PROPOSED ELECTRICITY RESOURCE AND BULK TRANSMISSION DATA REQUESTS

Prepared for the *2005 Integrated Energy Policy Report*

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STAFF REPORT

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INTRODUCTION

This document provides a detailed description of the information and analysis requested from third parties related to electricity planning, supply and transmission. It elaborates upon the staff report titled *Proposal to Assess Electricity Supply, Resource, and Bulk Transmission Planning Data* (in Docket 04-IEP-01-D) and is intended to inform parties from whom data is requested and stakeholders with an interest in the issues to be addressed, as well as analysis to support the *2005 Integrated Energy Policy Report* (*2005 Energy Report*).

The data submittals are categorized as follows:

- Resource plans from each of the state's major load-serving entities (LSEs). These plans include assessments of the major uncertainties which influence resource planning decisions and their impact.
- Information necessary to assess the potential need for additional procurement to ensure resource adequacy on both an individual-LSE and system-wide basis. This includes information on bilateral contracts, historical generation, and expected qualifying facility (QF) cost and performance.
- Information regarding planned transmission facilities from transmission-owning LSEs.

In many instances, the information requested by the staff differs depending on whether the LSE is an investor-owned utility (IOU), a municipal utility[1], or an energy service provider (ESP). This request stems from different requirements imposed upon each class of LSE by the Legislature and state agencies, materials created by each class in the course of doing business, and the information available from other sources.

RESOURCE PLANS

To assess resource adequacy, the staff requests that LSEs submit "ten-year" resource plans. The plan should describe projected loads, the expected operation of existing resources, and the resources expected to meet remaining load obligations. For submittals in 2005, the period is 2006-2016. The plan should assume that resources will be needed to meet a 15-17 percent planning reserve margin under expected (1-in-2) monthly peak load conditions and dry year (1-in-5) hydrology conditions. The plan should include, but not necessarily be limited to:

- A monthly capacity-resource accounting table (CRAT),
- A monthly energy balance table,

[1] Intended to include irrigation and water districts and authorities, community choice aggregators, and power pools.

- Descriptions of bilateral contracts,
- Descriptions of the characteristics of new resources needed to meet load,
- The impacts of potential changes in load obligations and other major uncertainties on the preferred resource plan and the associated changes in estimated costs, and
- An assessment of the set of resources assumed to meet load obligations given transmission constraints ("deliverability").[2]

In addition, the state's three major IOUs should be prepared to submit the following additional information:

- Impacts of desired upgrades to the bulk transmission system on preferred resource plans,
- Natural gas and wholesale electricity price forecasts used in simulations, and
- Estimates of future QF generation and costs.

LADWP and SMUD are asked to discuss any upgrades to the bulk transmission system that are assumed in their reference case resource plan. This discussion should describe the upgrade and its impact on their procurement choices.

The staff requests a "reference case": a resource plan that "assumes away" numerous uncertainties. We acknowledge, however, that potential changes in load obligations and other uncertainties are apt to affect the LSE preferred resource plans, especially the major IOUs. The analysis of these uncertainties may require or encourage the submittal of separate CRATs tables (and Energy Balance tables) for these "scenarios." This subject is discussed in detail in the section titled "Uncertainty Analysis – Scenarios" located on page 10.

The entries in the CRATs and Energy Balance tables for the reference case should be consistent with those in the Demand Forecast forms simultaneously filed with the Energy Commission in the *2005 Energy Report* proceeding.

Capacity/Resource Accounting Tables

The monthly CRATs tables[3] are designed to elicit information regarding

- Capacity provided by existing LSE resources.
- LSE needs for additional capacity during the next ten years (current net short position).
- Types of resources (baseload, shaping or peaking, seasonal vs. year-round, capacity vs. energy) needed to meet future energy and capacity needs.

[2] Public utilities are not requested to submit this component.
[3] The Electricity Supply Forms and Instructions will contain the detailed description of the requested information.

- Renewable resource commitments needed to meet existing and potential renewable energy purchase (RPS) targets or requirements and back-up for intermittent resources (if any).
- Potential capacity surpluses during non-summer months.
- Near-term and potential long-term reliance on short-term and spot markets.

While a single format is presented in the sample forms which accompany this document, the detail provided will vary by class of LSE. IOUs are asked to submit additional information, related to energy efficiency, demand response and qualifying facility (QF) and Department of Water Resources (DWR) contracts.[4] ESPs are assumed not to own generation and are thus assumed only to meet load obligations through existing and future contracts.[5]

The following subsections provide additional information regarding the composition of the CRATs tables.

Monthly Reporting

LSEs are asked to provide monthly values for 2006–2016 (this requirement also applies to the Energy Balance table). Monthly values provide insight regarding the need for seasonal capacity and energy, as well as potential capacity and energy surpluses during non-summer months.

Resource Accounting Conventions

The staff requests that LSEs provide dependable capacity values for each of their physical and contractual resources. To the extent that accounting conventions have been adopted in CPUC proceedings, the staff has adopted them for use in the IEPR filing. With one exception, dependable capacity is hereby defined as the output that can be sustained under peak load conditions (1-in-2 temperature and 1-in-5 dry hydrology conditions) for four hours for each of three consecutive days. The exception is interruptible load subject to LSE dispatch, also counted as a supply resource. This supply need only be counted on for 2 consecutive hours in a month. Capacity values should not be adjusted for expected forced outages, but the LSE should consider scheduled outages.

Those LSEs with hydro generation assets in their portfolio should indicate the expected derate for 1-in-5 year (dry) hydrology conditions and base their procurement needs on this reduced amount of hydro capacity.[6]

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[4] Information related to energy efficiency and demand response programs undertaken by public utilities has been requested elsewhere by the Energy Commission; see the Electricity Demand Forecast Forms and Instructions, adopted on November 3, 2004.
[5] Any ESP that owns generation facilities is expected to indicate these facilities as 'Utility-owned" generation in the CRATs table.
[6] In keeping with the recommendations in the *Workshop Report on Resource Adequacy Issues*, (R.01-10-024, R.04-04-003; June 15, 2004, p. 20), adopted in D.04-10-035.

IOU estimates of the dependable capacity associated with existing QF contracts should be based on historical average generation during peak hours (as defined in Standard Offer 1 contracts). LSE estimates of the dependable capacity associated with other non-dispatchable resources (both recently-procured resources for which there is a limited historical record and future "generic" resources for which no historical data are available) should be explained (as a percentage of installed capacity) in notes that accompany the CRATs table.

Preferred Resources

California policy makers have determined that the state should pursue an energy policy action plan with a loading order of preferred resources. The preferred resources are conservation and energy efficiency, price sensitive demand responses, renewable resources and distributed generation. A discussion of renewable resources is covered in a later section.

The California Public Utilities Commission (CPUC) established energy efficiency targets for both peak and energy for each of the IOUs [D.04-09-060]. These targets should be assumed to be met in the reference case. The energy efficiency targets represent the cumulative energy savings expected from IOU energy efficiency programs implemented between 2004 and 2016. As such, a share of the savings in these targets includes committed savings from program funding already approved by the CPUC for 2004 and 2005. These savings should be reflected in the retail load and sales forecasts submitted. For IOUs, the remaining share should be provided as a line item in the resource accounting and energy balance.

Price-sensitive demand response goals for the IOUs were established in D.03-06-032 (p. 10). These are 4 percent of the annual peak demand in 2006 and 5 percent in 2007 and thereafter.[7] The IOUs are asked to assume that these targets are met; the committed portion of price sensitive demand response should be included in the base load forecast, and the remaining, uncommitted portion as a line item entry in the CRATs table. To date, the CPUC has not established a target for customer-side distributed generation, but the IOUs are asked to provide an estimate of uncommitted distributed generation on the customer side of the meter as a line item entry in the CRATs table.

Following the adopted Demand Forms and Instructions, the IOUs are also asked to provide a line-item entry for their committed dispatchable demand response resources (*i.e.*, interruptibles/emergency response programs).

Municipal utilities and ESPs are not required to provide estimates of the capacity savings associated with energy efficiency, price sensitive demand response, or distributed generation. They may enter estimates as line-item entries if they wish

[7] It was further established in D. 04-06-011 that interruptible and emergency programs do not qualify to satisfy these price-responsive demand goals

to rely upon such resources in the future. Alternatively, projections regarding these values may be embedded in their peak demand estimates.

Preferred resources also include renewable resources; these are discussed in the section titled “Future Renewable Resources” located on page 7.

Direct Access/Core-Non Core

In the reference case the IOUs are asked to assume that direct access load they no longer serve continues to be served by other providers and that no current bundled customers take direct access service. A scenario under which load falls as a result of a future core/non-core policy decision is presented in the section titled “Uncertainty Analysis – Scenarios” located on page 10.

ESPs are asked to indicate the load obligations that arise from existing customers and those based on assumptions about new customers and contract renewals/extensions for existing customers. This should be a line-item in the CRATs and energy balance tables.

Community Choice Aggregation/Departing Municipal Load

The staff requests that the IOUs assume a level of community choice aggregation (CCA)/departing municipal load (DML) in their reference case and enter it as a line item in their CRATs tables. As likely CCA/DML values are both very uncertain and are apt to be utility-specific, the staff proposes that each IOU choose a CCA/DML level for its reference case that meets the following requirements:

> Load departure begins no earlier than 2007 and no later than 2013.
> Total departure over this period is at least 4 percent of bundled customer load and no greater than 10 percent.

If an IOU believes that this assumption does not accurately reflect the risk of departing load under CCA/DML, this should be explained in the filing.

The municipal utilities are asked to incorporate their assumptions regarding departing load directly into their total peak load estimates.

Energy-service providers are asked to distinguish between expected loads of those customers under contract and a residual which represents both new customers and the load associated with existing customers whose contracts are renewed.

Existing and Committed Supply Resources

When compared against forecasted loads, existing and committed supply resources provide insight as to the quantity and type of additional resources needed to meet future load obligations, subject to any procurement constraints imposed by regulatory or legislative bodies.

The staff asks that filed resource plans distinguish between existing and committed resources on the one hand, and future generic resources on the other.

Existing and committed resources include:

- Physical resources that are currently owned or under the control of the LSE or that the LSE presently expects to construct or purchase.
- Contractual entitlements to energy or capacity that are greater than or equal to 90 days in length or for multiple periods across calendar years (*e.g.*, July-August for 2006 and 2007).

This is intended to include resources that may not be in service or under the control of the LSE at present. The key characteristic of these committed resources is that the LSE presently intends to construct or purchase a specific facility or has already executed a contract for an energy or capacity product.

Each individual existing and committed resource, whether physical or contractual, should be a line-item entry in the CRATs table for those months that the LSE expects to own/control/contract with the resource. The following are exceptions:

- Capacity from (non-QF) hydro assets should be aggregated. A list of those hydro resources whose output contributes to a Renewable Portfolio Standard (RPS) energy requirement (installed capacity of 30 MW or less) should be presented in a footnote to the CRATs table.
- Capacity from QF contracts should be aggregated by technology.
    - Natural gas – cogen
    - Biofuels
    - Geothermal
    - Small hydro
    - Solar
    - Wind
    - Other

Although a long-term policy for expiring QF contracts is not expected from the CPUC until early 2005, in keeping with the proposed decision in R.04-04-003[8],

[8] Dated November 16, 2004

the IOUs are not required to assume any QF contract will be renewed or extended beyond those for which extension the seller has already been mandated. They are asked to indicate the aggregate capacity and energy of those QF facilities which are assumed, for planning purposes, to remain in service of the IOU's loads on a must-take basis beyond the expiration of existing contracts and mandated extensions. Two of the IOUs are asked to discuss a scenario in which all its QFs remain in service of its loads for the duration of the planning period as providers of must-take energy.[9]

Additional data requested below (see the section titled "Historical QF Generation, Estimates of Future QF Generation and Costs" located on page 14) regarding QF performance, contract expiration, and cost will provide the staff with information regarding the potential impact of QF retirement on net-short positions, additional renewable energy needs, etc.

As discussed in the section titled "Resource Accounting Conventions" (located on page 3), capacity should be based on historical performance, with average generation during each month's (SO1) peak hours as the basis for the capacity value.[10] Footnotes to the CRATs table should explain how the values associated with QFs were derived. Should the filing IOU believe that there is a more appropriate methodology for computing expected capacity, the methodology should be presented and explained in an attachment to the resource accounting table, including a summary of the impact of the change on derived values.

The capacity that should be attributed to individual and aggregated resources is also discussed in the section titled "Resource Accounting Conventions" located on page 3.

All LSEs are asked to submit additional information regarding bilateral contracts that they have entered into; see the section titled "Bilateral Contracts" located on page 14.

Future Renewable Resources

The staff acknowledges that the role of various technologies in meeting renewable energy targets and the location of yet-to-be built renewable facilities cannot be forecast with a great deal of confidence. Several factors will determine the composition of renewable resources in California and the West at the end of the planning period, including relative changes in the costs of development and generation, market maturation, upgrades to the bulk transmission grid over the next decade and the future role of tradable RECs. On the other hand, renewable procurement efforts to date have provided the state's IOUs with insight as to the

[9] Because of the small amount of QF capacity with expiring contracts with SDG&E, it is not asked to provide this assessment.
[10] In accordance with the direction given in D.04-10-035 (p. 24).

relative competitiveness of various renewable technologies, as well as their current and perhaps future availability.

The IOUs are asked to provide resource plans which enable them to meet a renewable energy target of twenty percent of retail sales by 2010 and maintain purchases at that level through 2016. They are asked to provide their best projections of the energy and associated capacity that will meet these targets by location (CA ISO zone and control area) and technology (geothermal, biofuels, wind, solar). The IOUs will be filing ten-year renewables plans at the CPUC, and the two filings should be compatible.

Notes in the CRATs tables submitted by the IOUs should describe the relationship between nameplate and dependable capacity for all intermittent resources. IOUs are asked to discuss in narrative form any impact that intermittence is anticipated to have on the procurement of the remainder of its portfolio.

To the extent that a municipal utility has made a firm commitment to a renewable acquisition policy, it is asked to specify generic renewables separate from its future generic resources and provide its best projections of the annual capacity and energy from these resources. All municipal utilities are requested to submit the most recent annual report to their customers pursuant to PUC Section 387(b).

In providing their projections for both the reference case and the accelerated renewables scenario (see the section titled “Uncertainty Analysis Scenarios” located on page 10), the IOUs, LADWP and SMUD should describe the potential cost (direct costs, additional transmission, etc.) to ratepayers of meeting these RPS goals. They are also asked to describe barriers which limit their ability to implement or enforce an RPS and what might be done to reduce or overcome each such barrier.

Capacity Reserve Requirements

Pursuant to D. 04-101-050, IOUs and ESPs are required to meet a 15-17 percent planning reserve margin.[11] Municipal utilities may presently plan to rely on near-term forward and spot market purchases for a share of their energy needs. In either case, the LSE is asked to indicate what type of generic resource would be expected to meet a reserve requirement and energy needs most cost-effectively, even though the forward procurement of such a resource is not presently planned.

[11] Meeting this reserve requirement in 2006 was directed in R.04-04-003

Future Generic Resources

Most, if not all, LSEs will need to procure additional resources to meet load obligations during the next ten years. In some instances, LSEs have committed to specific but yet-to-be-built physical resources. In others, LSEs have recognized the future need for capacity and/or energy, but have not begun to consider specific projects or whether these needs can be best met with physical or contractual resources. However, given forecasted loads and necessary reserves, all LSEs can reasonably be expected to provide an estimate of the load that these resources will meet, and thus whether baseload, shaping or peaking resources will be needed, and if the latter, whether this need will be seasonal or year-round.

Accordingly, the staff asks that all LSEs proposing generic generation resources indicate the type and amount (MW) of resources that are expected to be needed to meet load and reserve needs. Resources can include the following:

- Physical, contractual, or demand-side (year-round) resources to meet baseload energy needs.
- Physical, contractual, or demand-side (year-round) resources to meet load following, shaping or peaking needs.
- Contractual or demand-side resources to meet load-following, shaping or peaking energy needs on a seasonal basis.
- Contractual or demand-side resources needed to meet peaking capacity needs on a year-round basis.
- Contractual of demand-side resources needed to meet peaking capacity needs on a seasonal basis.

Energy Balance Tables

The staff asks that the LSEs submit energy balance tables that correspond one-to-one to their CRATs tables. These provide estimates of the energy from each of their resources.

- Monthly values should be provided as indicated in the section titled “Monthly Reporting” located on page 3.
- It is not necessary for IOUs to estimate the energy associated with price-sensitive demand response.
- Energy from hydro resources should be divided into energy from facilities with a nameplate capacity of 30 MW or more and less than 30 MW.

Other Information Related to Reference Case Resource Plans

Input Assumptions

The staff requests that the IOUs provide the natural gas and wholesale electricity price estimates used in their analyses. Wholesale electricity price estimates should be consistent with gas prices. Natural gas prices should be based on current forward prices in the near-term, but may, at the utility's discretion, be based on a fundamentals model over the longer-term. Should such a model be used, any significant differences between forecasted prices and those indicated by current forward prices, and their extrapolation, should be explained. Should an IOU use yet another methodology for determining long-run gas prices, it should be explained in documentation which accompanies the price forecast.

Resource Plan Costs

The staff asks that the IOUs provide estimates of the annual costs of meeting load obligations for the reference case resource plan. These costs should include, but not necessarily be limited to the variable costs of operating utility-owned generation, contract costs, and the net revenue from activity in the wholesale market. Any additional, significant, and quantifiable costs which facilitate comparisons between the reference case resource plan and additional scenarios should also be presented. In addition, any significant costs whose determination is beyond the scope of analysis requested should be discussed.

Uncertainty Analysis Scenarios

The staff asks that LSEs provide an assessment of the impact of major uncertainties on their preferred resource plans. The following outlines the staff's thinking about key sources of uncertainty.

Core/Non-Core-Departing Load

The major uncertainty facing the state's IOUs is future load obligations, which will be influenced by policy decisions related to core/non-core and community choice aggregation and municipalization (CCA). Procurement of resources in excess of the amount ultimately needed by IOU bundled customers may result in stranded costs. Reducing the risk of stranded costs in the face of load uncertainty has required a portfolio of resources of diverse durations. The forthcoming procurement decision in R.04-04-003 will provide some direction regarding stranded costs, but the basic uncertainty still exists.

The staff proposes that the IOUs submit a "low load" resource plan that assumes that 75 percent of customers with peak demand of 500 kW[12] or more will depart during 2009-2012 (30 percent in 2009, 15 percent in each of 2010-2012). Should an IOU believe that another core/non-core scenario provide additional information regarding the risks that it faces, it is encouraged to provide an additional scenario.

Accelerated Renewables

The Energy Commission adopted the following recommendations in its *2004 Energy Report Update* for achieving ambitious renewable energy goals:

> The state should enact legislation to require all retail suppliers of electricity, including large publicly-owned electric utilities, to meet the accelerated 20 percent eligible renewable goal by 2010 and a longer-term goal of 33 percent by 2020, using common definitions of eligible renewable energy. In addition, the state should enact legislation that allows the CPUC to require Southern California Edison (SCE) to purchase at least one percent of additional renewable energy per year between 2006 and 2020, reaching 25 percent by 2010, 30 percent by 2015 and 35 percent by 2020.

To assess the implications of the *2004 Energy Report Update* recommendations, PG& E, SDG&E, and the large publicly-owned electric utilities (LADWP, and SMUD) should provide an alternate case that has 28 percent of retail sales served by eligible renewable energy[13] by 2016 (28 percent is the 2016 value for the 33 percent by 2020 target). In the case of SCE, they should provide a scenario that has 31 percent of retail sales served by eligible renewable energy by 2016.

All of the LSEs expected to file this scenario should provide a plausible projection of the technologies and locations of the resources projected to meet this accelerated requirement.

Major Transmission Upgrades

If the LSE reference case assumes an upgrade to the bulk transmission grid that has yet to receive regulatory approval, the staff also requests submittal of a modified version of the same resource plan without the upgrade. Essentially this means a "with and without" analysis. The reference case analysis should detail the changes in the direct costs of meeting load and reserve obligations that the upgrade makes possible, assess any additional benefits that the upgrade may

[12] Individual customers are assumed not to be allowed to aggregate loads at different sites in order to reach the 500 kW threshold.
[13] Public Utilities Code Section 399.12 (a)(1-4)

provide, and explicitly state the changes in assumptions (*e.g.*, import capability and quantities, changes in wholesale prices) in the two cases.

Qualifying Facility Extensions

The IOUs are asked to assess the impact of the extension of all QF contracts for the duration of the planning period on their reference case plan. The IOUs are not asked to estimate cost differences, but merely to indicate how future resource procurement might be affected given continued purchase of must-take energy from all existing QF resources.

Sensitivity of Resource Plans to Natural Gas and Wholesale Electricity Prices

The LSEs are asked to provide an estimate of the effect of long run changes in natural gas and wholesale electricity prices on the cost of meeting their load obligations in each year in the reference case. Bounding estimates should be based on prices in the tenth and ninetieth percentiles. The resulting impact on the assumed wholesale electricity price should reflect appropriate input price elasticities.

Potential Impact of a Greenhouse Gas Adder on Bid Evaluations

The Proposed Decision of November 16, 2004, in R.04-04-003 requires that the IOUs apply a greenhouse gas (GHG) adder to bids received in response to future solicitations for energy and capacity, as well as to consider GHG emissions in their long-term planning process. The value of the GHG adder is to be determined in R.04-04-025 in March 2005.

The staff requests that the IOUs submit a discussion of the potential impact of a GHG adder (using a CO_2 adder as a proxy) on future procurement choices. A reasonable range of values, at least \$8 - \$25/ton CO_2 should be discussed.

Deliverability

Effective resource planning requires that energy generated by projected resources be deliverable to load; the requirement that the IOUs evaluate deliverability in their long-term procurement filings was imposed in R.04-04-003.[14] Accordingly, the staff intends to request information from the IOUs and ESPs on their projected ability to meet expected peak loads given both interzonal and intrazonal transmission constraints.

[14] See, for example, the Interim Order Regarding Electricity Reliability Issues dated June 28, 2004.

The CPUC's ongoing resource adequacy and procurement proceedings have yet to resolve how deliverability is to be evaluated; it is, therefore, not possible to determine fully which resources are deliverable to load. This makes it difficult to determine what data and analyses are necessary to provide policymakers with useful information regarding deliverability. Comments at the workshop will be particularly helpful on this point.

The staff could simply request load forecasts and resources within the relevant CA ISO local reliability areas from each of the IOUs and ESPs, but this may not provide a complete set of useful information. Some deliverability concerns arise from intrazonal transmission constraints that are not associated with local reliability areas. These may require projections of loads and available resources within areas that remain to be defined.

The staff proposes revisiting this issue at such time that consultation among the Energy Commission, CPUC, CA ISO, and IOUs can provide additional direction regarding the procurement constraints that need to be met by the IOUs to ensure local reliability, as well as the data needed to assess whether a given resource plan meets local reliability requirements.

Other Scenarios

The staff has proposed a limited set of scenarios for analysis. Parties are asked to recommend additional scenarios for review. In particular, the LSEs are encouraged to suggest scenarios which highlight the risks that influence their resource planning.

Quantitative Analyses of Uncertainty

The foregoing subsections discussed key uncertainties that staff believe must be assessed. The staff does not believe all of these uncertainties merit a complete optimization of the resource plan. The staff believes that some uncertainties have sufficient impact that reoptimized resource plans are necessary, while others may be illuminated with more simplistic sensitivity studies.

The staff proposes to schedule a workshop devoted on the quantitative assessment of uncertainty of supply and demand input to determine what assessment techniques should be used. Once greater clarity about the range of likely impacts and the "costs" of deploying alternative assessment techniques is better understood, the staff may recommend additional filings to address these assessments.

As noted in the discussion of various uncertainties, the staff does not believe that all LSEs face the same uncertainties nor should all LSEs be expected to conduct the same assessments. In terms of required assessments, the IOUs should be asked to do more because the regulatory environment creates greater uncertainty, and they have greater impacts on the overall system, thus justifying greater efforts to quantify these impacts.

OTHER DATA REQUESTED

The Energy Commission staff is requesting additional data to both inform the CPUC procurement proceeding and undertake additional analysis to support the *2005 Energy Report*.

Bilateral Contracts

The staff requests detailed information regarding bilateral contracts for the purchase of energy and/or capacity.[15] The purpose of this request is to:

- ascertain the extent to which existing contracts are likely to satisfy resource adequacy and deliverability requirements that may be imposed in the future,
- assist in determining which specific generation capacity both in- and out-of-state is encumbered in service of California loads, and
- provide information regarding the exposure of California ratepayers to long-run changes in the natural gas price.

See Form S-3 in the Electricity Supply Planning Forms and Instructions.

Historical QF Generation, Estimates of Future QF Generation and Costs

The staff requests historical hourly purchases from individual QFs for 2003 and 2004. For contracts with a capacity of less than 10 MW, hourly generation values should be aggregated by technology. These data will allow staff to evaluate the capacity values attributed to existing QF resources.

The staff requests estimated annual capacity, generation, and cost estimates for individual QF contracts for 2006 -2016. These data will allow staff to address the following questions:

- What are the resource adequacy impacts of expiring QF contracts? What share of this impact arises from the expiration of the handful of largest contracts?
- Regarding replacement costs, what are the implications of expiring QF contracts for energy and capacity costs under different assumptions?
- How do various QF contracts affect the net short/long energy position and address reliability concerns?

[15] These data are requested for bilateral contracts other than DWR and QF contracts.

- What are the potential impacts of expiring contracts on the incremental need to procure renewable energy?
- What contribution do QF contracts make to natural gas price risk faced by California ratepayers?

Additional Wind Generation Data

The administration and public support the continued development of renewable energy resources, which the RPS codified in the state's Energy Action Plan, pointing to increasing the use of wind energy to meet the state's energy needs. The existing data are not sufficient, however, to evaluate the reliability impact of wind energy, as well as the disparate claims regarding the likely performance and capacity value of wind facilities that are now being brought on line or undergoing retrofits.

The staff requests that both the buyers and sellers of wind energy in California submit hourly historical wind generation data. Currently, the staff receives a limited amount of such data on a voluntary basis, from those owners who agree to provide it.

A substantial share of the wind generation in California is provided to IOUs under QF and RPS contracts. To ease of burden, the IOUs, rather than the individual generators, should provide these data. Data on QF generation have been requested in the section titled "Historical QF Generation, Estimates of Future QF Generation and Costs" located on page 14. Where wind projects are owned by LSEs or wind energy is purchased by LSEs under (non-QF) contracts involving projects of 10 MW (nameplate) or more, the staff asks that these entities provide hourly purchase data. The staff also requests that merchant wind generators larger than 10 MW (nameplate) report their hourly injections onto the transmission grid.

Additional data from selected individual generators will be necessary to establish the performance of new wind generation technologies. Information regarding the turbine models will allow the staff to determine which output may be considered from "state-of-the-art" resources. In cases where technologies of multiple vintages are in use, the staff would like, where possible, to allocate hourly generation across them. A blanket survey of wind generators, while providing the information needed, would likely involve an unnecessary expenditure of time and resources. Prior to recommending such a survey, the staff proposes consulting with California Wind Energy Association (CALWEA) and the California Wind Energy Collaborative to compile a list of generators from whom data would be of value, as well as designing forms and instructions for the submittal of data related to turbine type and, where indicated, more detailed hourly generation data. If these efforts do not prove successful, the staff anticipates returning to the Committee with a request to solicit hourly generation data from the appropriate entities.

Selected Hourly Hydro Generation Data

The staff lacks sufficient data to assess the system-wide availability of hydro generation and capacity during peak hours in the summer, as well as the role that individual generation facilities play in meeting peak loads. This information is needed to evaluate whether California has sufficient generation capacity to meet the demand for energy reliably, and the capacity value of individual facilities relative to their environmental impact.[16]

The staff requests historical hourly hydro generation data from selected hydro asset owners to evaluate hydro availability during peak hours and under a range of hydrology conditions. The CA ISO has already provided hourly data on the performance of many of the state's hydro facilities, but the Energy Commission staff has been restricted in its use of the data for analysis.[17] These hydro facilities include those of most of the IOUs and the hydro resources in the CA ISO control area operated by public utilities and irrigation and water districts. The remaining data needed by staff primarily relates to those hydro facilities operated by public utilities outside the CA ISO control area, and includes the following operators:

- Los Angeles Department of Water and Power
- Sacramento Municipal Utility District
- Imperial Irrigation District
- City and County of San Francisco PUC/Hetch Hetchy Water and Power
- U.S. Bureau of Reclamation
- Turlock Irrigation District
- Metropolitan Water District

The staff requests historical data for 1998-2004 and in future cycles for the two preceding calendar years. These data need to be disaggregated by facility and should include values for pump storage facilities.

The staff may ask the Committee at a later date for additional historical hydro data for use in future IEPR analysis.

PLANNED TRANSMISSION FACILITIES

The Energy Commission is required by Public Resources Code section 25324 to create a statewide strategic transmission plan. To fulfill this order, the Energy Commission is requesting all transmission-owning LSEs to submit data on their planned expansion of the bulk transmission grid over the next ten years (2006-

[16] The staff is requesting these data, in part, to be used for analysis in the Environmental Performance Report.
[17] The staff assumes that this data, obtained pursuant to SB1305, may henceforth be used in all *2005 Energy Report*-related analyses subject to confidentiality restrictions.

2015) and a less specific discussion of transmission strategies over the next twenty years. The transmission submittals along with the CA ISO 2004 Grid Study and the *2005 Energy Report* record will be used to develop the strategic transmission plan. There are ongoing meetings between the Energy Commission, CA ISO and the CPUC intended to develop a coordinated transmission planning and permitting process. A status report on this meeting will be presented at the December 21, 2004 workshop, and the results of the meetings could impact the Energy Commission's data needs.

LSEs are required to procure resources to meet RPS standards, meet resource adequacy requirements, lower the cost of serving loads, and meet Western Electricity Coordinating Council (WECC), North American Electric Reliability Council (NERC) and other reliability criteria. The development of additional transmission projects may play a key role in each transmission owning LSEs long term strategies to meet these requirements. This should be a qualitative discussion of potential strategic transmission resources that identifies specific projects and issues that may hinder their development. LSEs should also identify any potential corridor needs vital to the long-term development of strategic transmission projects.

All transmission owning LSEs will be required to file a description of their transmission planning and permitting process as well as data on their planned expansion of the transmission network. Where a transmission project is planned by a non-LSE, the LSE owning the facilities to which the project interconnects will be responsible for filing data at the Energy Commission. Agencies such as the Transmission Agency of Northern California that include in their membership many transmission owning LSEs could submit data for their members.
While it is not the staff's intent to create a large filing burden on transmission-owning LSEs, our efforts to better integrate generation and transmission planning could have consequences not yet fully understood. Thus, in addition to the transmission planning results themselves, each LSE submitting transmission plans should provide documentation of the reference case resource plan to characterize loads and generation resources. This documentation should identify the discrepancies between the loads and generation resources used in the transmission planning studies and the reference case provided as a result of the adopted *2005 Energy Report* Demand Forms and Instructions and the resource plan described earlier in this white paper. To the extent that loads and generation resources included within the transmission planning tools are different in other than trivial fashion, then an estimate of the implications of these discrepancies should be provided.

Further, since transmission plans inherently require location, utilization characteristics, and size of generation facilities that cannot be known with precision, the larges projects (classified as Tier 3 below) must be studied using multiple generation expansion scenarios in addition to the reference case. These scenarios should explore broad thematic generation expansion paths consistent with policy options state energy agencies are now considering. For example, one alternative scenario should examine greater levels of renewables than those required in the reference case. Another scenario should examine continuations of the gas fired combined cycle generation additions of the past decade that are relatively close to California load centers. A third scenario should examine reliance upon out of state coal or gas fired combined cycle facilities closer to fuel sources.

To create a complete, public record in the *2005 Energy Report* proceedings and to make the data available to the public, LSEs will be required to file data in the Energy Report docket that may be available to stakeholders in other forums. However, the staff has attempted to reduce the burden of these filings by basing the data requests on the filings from other forums. The data requirements are tiered, with more data being required on large projects than on the smaller projects. Transmission facilities at the distribution level do not need to be included at any level. For large projects, costing over $100 million, economic assessments of both the proposed facilities and reasonable alternatives will be required. The purpose of these forms is to provide as much detail as is available on transmission facilities planned over the next 10 years (2006 through 2015). The staff is willing to consider alternative formats if equivalent data are included. The staff's proposed data requirements consist of three tiers:

1. Tier 1 is for small projects costing less than $20 million. Data requirements for Tier 1 consist of a table listing the project and a brief description (see Attachment 1).
2. Tier 2 will apply to projects that cost between $20 million and $100 million. Data requirements for Tier 2 consist of a several-page description of the project including a discussion of project alternatives (see Attachment 2).
3. Tier 3 applies to all projects over $100 million. Data requirements consist of a full analysis of the project, including a discussion of the assumptions used in studies, and an analysis of non-transmission alternatives.

Finally, all Tier 3 projects must be described in the context of the variations in study results among the various generation expansion scenarios that have been investigated. To properly accomplish this requires a narrative description identifying the range of results for each Tier 3 project, and rationale for the alternative results, and the degree to which the results across multiple scenarios are identical or similar.

Tier 1 Transmission Projects (under $20 million)

The form for bulk transmission projects under $20 million is presented in Attachment 1.

Project Name should include the geographic endpoints, and the primary project facilities.

Location refers to the project location should include the county, and the city and local reliability area if applicable.

Project Description should provide a complete list of the major facilities required for the project. Where the designated project requires other transmission system reinforcements, those should be listed as part of the project entirety.

Rating refers to the installed ratings (kV and MVA) of facilities involved in the project.

Cost refers to the estimated project cost in millions of dollars.

Date in Service refers to the expected date of commercial operation.

Purpose and Benefit: Describe what the project will accomplish, enable, or better facilitate. Note significant changes or improvements expected for the transmission network. List the qualitative and approximate quantitative benefits expected to be provided by the project, and who will receive those benefits.

Potential Issues: Briefly state any issues that may delay or prevent the project from operating on the expected date of commercial operation.

Also provide the modeling specification for the project or the characterization of the project in the GE PSLF model.

Tier 2 (Projects between $20 million and $100 million)

Attachment 2 is a three-page example of a filing for a $20 million to $100 million project.

Project Name: Provide the general project name.

Project Description: Provide a complete description of all the facilities [same problem as noted above] associated with the project and the expected in service date. If the project was identified in a publicly available annual report, indicate the title and year of the report.

Project Background and Purpose: Provide significant detail on the background for the project including a description of the region and the conditions affecting the need for the project. Provide a list of the overloads and/or congestion problems the project addresses, and how these overloads and congestion problems will be reduced by the project. Briefly describe the expected project benefits in qualitative and quantitative terms, and identify who will receive those benefits. Describe how transmission system changes will serve and integrate with expected development of generation facilities including renewable generation facilities that meet RPS goals.

Project Alternatives: Discuss the alternatives to the project including both transmission and non-transmission options. If non-transmission alternatives were not seriously considered, explain why they were not considered. For the alternatives, provide rough cost and benefit estimates, and the reasons why alternative projects (and the "no project" option) were not chosen.

Study Assumptions: Briefly describe the major forecasts, beliefs, and trends that were assumed in studies analyzing the project. At a minimum, this should include the WECC or other load flow data, and any substantive changes to the load and resource assumptions used in their study.

Key Uncertainties: Discuss potential problems and conflicts that may slow or prevent the development of the project, especially including permitting, potential corridor related issues, environmental concerns, and financing.

Project Status/Schedule of Milestones: Provide a list of key project milestones and a rough estimate of the month they are expected to be completed. For milestones that have already been met provide the completion date.
GE PSLF Modeling Information: Provide the GE PSLF (or other similar model) description of the project.

Diagram of the Project (Scope Diagram): Provide a schematic line diagram of the project including important major geographic references such as cities and substations near the project. This should provide enough detail to describe the project adequately (see Attachment 3 for a diagram example).

Large Projects (Over $100 Million)

All information for the Tier 2 project is also required for large projects, plus a more detailed economic and alternatives analysis. For large projects, the staff will require planning studies showing the project is needed for system reliability, that the project provides economic benefits, or that the project is needed to meet renewable resource targets. This should be a clear and thoughtful planning document. Define a clear problem that the proposed project is designed to solve, then develop and appraise decision criteria, and identify assumptions. Analyze existing conditions and forecast trends. Propose and consider alternatives to address the problem, including non-transmission alternatives. Do a complete analysis and evaluation on the best options.

At a minimum the study should include the following:

- A clear description of the problem the project addresses and the criteria which will be used to evaluate the project and potential alternatives.

- Cost estimates for the project and alternatives should include estimated annual carrying charges.

- All assumptions used to analyze the project.
  - Load forecasts
    - Where several forecasts (on/off peak, 1 in 5, or 1 in 10) are used list them all. Describe the source of the load forecast, the vintage, and describe how it differs from the reference case filed in the Demand Forms and Instructions.
  - Generation assumptions
    - Retirement assumptions.
    - New generator assumptions
    - Hydroelectric availability/scenarios.
    - Describe the source of these assumptions, the vintage, and how these differ from the reference case information for generation described in the generation portion of the Supply Forms and Instructions. Clearly identify which generation scenario embodied in the study assumptions.
  - Transmission assumptions
    - At a minimum, these should include the name of the load flow case the studies were based on, and a list of projects added beyond the specified case. If this case is not available to stakeholders, the load flow case should be submitted as well.
    - Detailed discussion of the projected impacts of the project/alternatives on WECC paths and on congestion in California.
  - Fuel prices used to calculate the impact of the project/alternatives on electricity production costs provide in both real 2005 dollars and escalated values
    - Where multiple fuel prices were used include those as well.

- A discussion of the social discount rate used and the reason it was chosen.

- Project Benefits
  - The effect of the project and alternatives on the need for other planned transmission facilities
  - Potential impact of the project and alternatives on must-run needs/costs in California.
  - Effect of the project and the alternatives on the ability of the network to meet WECC or other control area reliability/planning criteria.
  - Discussion of the project/alternatives insurance benefits.
  - Analysis of other strategic benefits provided by the project or its alternatives.
  - Sensitivity studies analyzing expected project benefits under various load, fuel and resource assumptions.

- Describe the modeling and other tools used in the analysis of the project.

FILING DATES

The staff requests that the data requested be submitted to the Energy Commission by March 1, 2005.[18] The staff assumes that the Energy Commission will establish procedures for considering requests to delay submittal beyond this date. In this cycle, data and analysis related to uncertainties ("scenario analysis") are requested by April 1, 2005.

DISCOVERY

While cooperation from entities asked to submit filings is expected, the staff foresees the possible need for clarification regarding data and analysis provided (e.g., methods and assumptions used to calculate values, assumptions used in simulations). Accordingly, the staff anticipates the need for on-going discussion with the parties to facilitate a clear understanding of the data requests and the materials submitted in response to those requests.

[18] The staff acknowledges that the IOUs submitted similar data and analyses as recently as July 2004 in the CPUC's Long-term Procurement Proceeding. The need to submit data and analyses only months later is a one-time consequence of the need to synchronize the *Energy Report* process and the Long-term Procurement proceeding to facilitate their integration. IOUs should determine the extent to which data previously submitted to the CPUC are still relevant in determining how to comply with these Energy Commission requirements.

Attachment 1 - Data for Bulk Transmission Projects under $20 million

PROJECT NAME	LOCATION	PROJECT DESCRIPTION	RATING	DATE IN SERVICE	COST $MM	PURPOSE & BENEFIT	POTENTIAL ISSUES
BART SFO Extension-Shaw Road Sub	Peninsula	Interconnect BART's Shaw Substation to the transmission grid	115 kV	Jan-02	$0	Reliability: Serve new loads	
Cortina-Colusa 60 kV Transmission	Sacramento	Reconductor portion of the Cortina-Colusa 60kV Transmission Line # 3	60 kV, 53 MVA	Feb-02	$232k	Reliability: Increase 60kV supply at Colusa Substation	
Kerckhoff 2 Circuit Breaker	Yosemite	Install a 115 kV circuit breaker at Kerckhoff 2 Powerhouse to establish two circuits from Kerckhoff 2 Powerhouse to Kerckhoff 1 Powerhouse	115 kV, 2000 Amps	Mar-02	$1.9 Million	Reliability: Increases reliability by enabling transmission over second line when first line is out of service	

Attachment 2 - Bulk Transmission Projects (Over $20 Million and Less than $100 Million)

This is only an example

Project Name:
Metcalf-Moss Landing 230 kV Reconductor

Project Description:
Reconductor approximately 35 miles of the Metcalf-Moss Landing 230 kV double circuit tower-lines with 954 SSAC conductors and upgrade associated line terminal equipment to accommodate the higher capacity ratings for the Metcalf-Moss Landing 230 kV double circuit tower-lines. It is estimated that the project will cost approximately $29 million.

Project Background and Purpose:
Bay Area load is served by a combination of in-area generation and power imported via three major import paths: from the Vaca-Dixon, Tesla and Moss Landing Substations. A general representation of this region of the Bay Area transmission system is shown in Figure 1. A stakeholder study entitled "Bay Area Bulk Transmission Reliability Improvement Project" was completed by PG&E in 2003. In general, the study results indicated that a long-term need existed to reinforce the 230kV transmission path from Moss Landing substation to serve future load growth in the Greater Bay Area. As such, the study recommended alternatives to increase the ability to move power from the Moss Landing substation into the Greater Bay Area.

The need to address the Metcalf-Moss Landing 230kV path is primarily related to inadequate transmission line capacity in conjunction with generation interconnected at the Moss Landing facility. Approximately 2,600 MW of generation is interconnected at Moss Landing. Dispatching all this generation simultaneously pushes a significant amount of power from Moss Landing to Metcalf. Under certain single contingency conditions, the Metcalf-Moss Landing 230kV lines will overload without the use of a special protection scheme. That scheme trips 1100 MW of Moss Landing generation that is connected to the Moss Landing 230kV bus if power flows across the Metcalf – Moss Landing 230kV lines exceed their thermal capability. At the present time, tripping this amount of generation is sufficient to address the overload conditions. However, by 2006 and beyond, generation tripping will become insufficient to mitigate these thermal overloads, and firm load shedding would be required without this project. CA ISO planning standards do not allow firm load to be shed for single contingencies. Therefore, additional transmission reinforcement is required before 2006.

The Metcalf-Moss Landing Reinforcement Project will avoid a requirement for load dropping due to a single contingency outage. The Project will also eliminate the requirement to trip 1100 MW of generation until the year 2017. Further, the

Project significantly reduces the amount of generation tripping and load dropping required to protect against worst double contingency outages. Lastly, the Project significantly improves the overall power import capability to the Bay Area, thereby reducing overall production costs across the Greater Bay Area.

Project Alternatives:
In general, the “Bay Area Bulk Transmission Reliability Improvement Project” study recommended the following reinforcement alternatives for this problem:

1. Reconductoring the Metcalf-Moss Landing 230 kV lines with 954 ACSS conductor.
2. Build new Metcalf-Moss Landing # 3 & 4 230 kV lines. Reconfigure the existing Metcalf-Moss Landing # 1 & 2 lines. Also reconfigure the Hicks-Metcalf and Vasona-Metcalf 230 kV lines to the Hicks-Moss Landing and Vasona-Moss Landing 230 kV lines.
3. Build a new Metcalf-Moss Landing #2 500 kV line.

Since all three alternatives will mitigate the reliability violation in the area, an economic assessment of these alternatives was conducted to facilitate the selection of the best alternative for CA ISO ratepayers.

The economic assessment of the three transmission alternatives analyzed factors relating to equivalent facilities, generation tripping, load dropping, loss savings, and generation-related benefits. The assessment of generation related benefits were included production cost savings resulting from an increase in overall Greater Bay Area import capability, leading to a decrease in overall generation costs. Changes in the Bay Area generation production costs and import costs stemming from the increased Bay Area import capability were simulated using a production cost model (MultiSym). Model runs using Monte Carlo draws demonstrated increased opportunities to utilize low-cost generation, when available).

Three scenarios were studied:

- a baseline production cost simulation benefit (or average hydro scenario),
- a high production cost simulation benefit (or wet hydro scenario), and
- a low production cost simulation benefit (or dry hydro scenario).

Due to its low capital cost, and high sensitivity to production cost, Alternative 1 (reconductor) returned the best benefit-cost ratios among the three reinforcement options. Alternative 1 is the only one with a benefit-cost ratio greater than one for all three generation scenarios.

Study Assumptions:
Two sets of base cases were developed from the 2002 base case series (names here) for use in this study. The first base case modeled projected year 2007 system conditions with about 9,700 MW of Greater Bay Area demand. (This is the projected load for a 1-in-10 year adverse weather condition for 2007 from the

2002 forecast). The second base case modeled projected year 2012 system conditions, except that the Greater Bay Area demand was assumed at 12,000 MW (which is the projected 1-in-10 load for 2018 of the 2002 base case).

The CA ISO Grid Planning Criteria were used to assess this project. In conformance with CA ISO's Planning Standards, Potrero Unit No. 3, Potrero Unit No. 6, and Oakland PP Unit No. 1 were modeled off line in the study cases.

Key Uncertainties:
Costs may increase if additional construction is needed.
Generation curtailments may be required during construction.
Environmental concerns, which will be identified during the permitting phase of the project, may require avoidance, reductions, mitigation, or offsets to potential adverse impacts. For example, clearing of knobcone pine for right-of-way work across the Santa Cruz Mountains will probably require contributions to enhance or restore comparable knobcone pine habitat elsewhere in the Santa Cruz Mountains. Studies of potential marbled murrelet habitat will be required where the existing T-line crosses land within five miles of predominantly redwood mature forest habitat.

There could be interactions with other projects that haven't been accounted for.

Project Status/Schedule of Milestones:

- CA ISO Needs Analysis – April 2003
- Economic Assessment – November 2003
- Environmental Impact Report (EIR) filed – June 2004
- Construction and Operations Contracts – September 2004
- Financing Secured – December 2004
- Design – March 2005
- CEQA Permits (or Negative Declaration) issued– March 2005
- Construction initiated– May 2005
- Construction completed – September 2005
- Commercial Operation Date – October 1, 2005
- Date Needed for Reliability – June 1, 2006

GE PSLF Modeling Information:
OLDSECDD 30735 30755 1 RPU=0.007253 XPU=0.52162 MVA1=805 MVA2=843
OLDSECDD 30735 30755 1 RPU=0.007253 XPU=0.52162 MVA1=805 MVA2=843

Attachment 3 - Sketch of San Francisco Peninsula Transmission System (From Staff Local Systems Effect Testimony for the Potrero Power Plant Unit 7 Project)